Do Electricity Prices Reflect Economic Fundamentals?: Evidence from the California ISO

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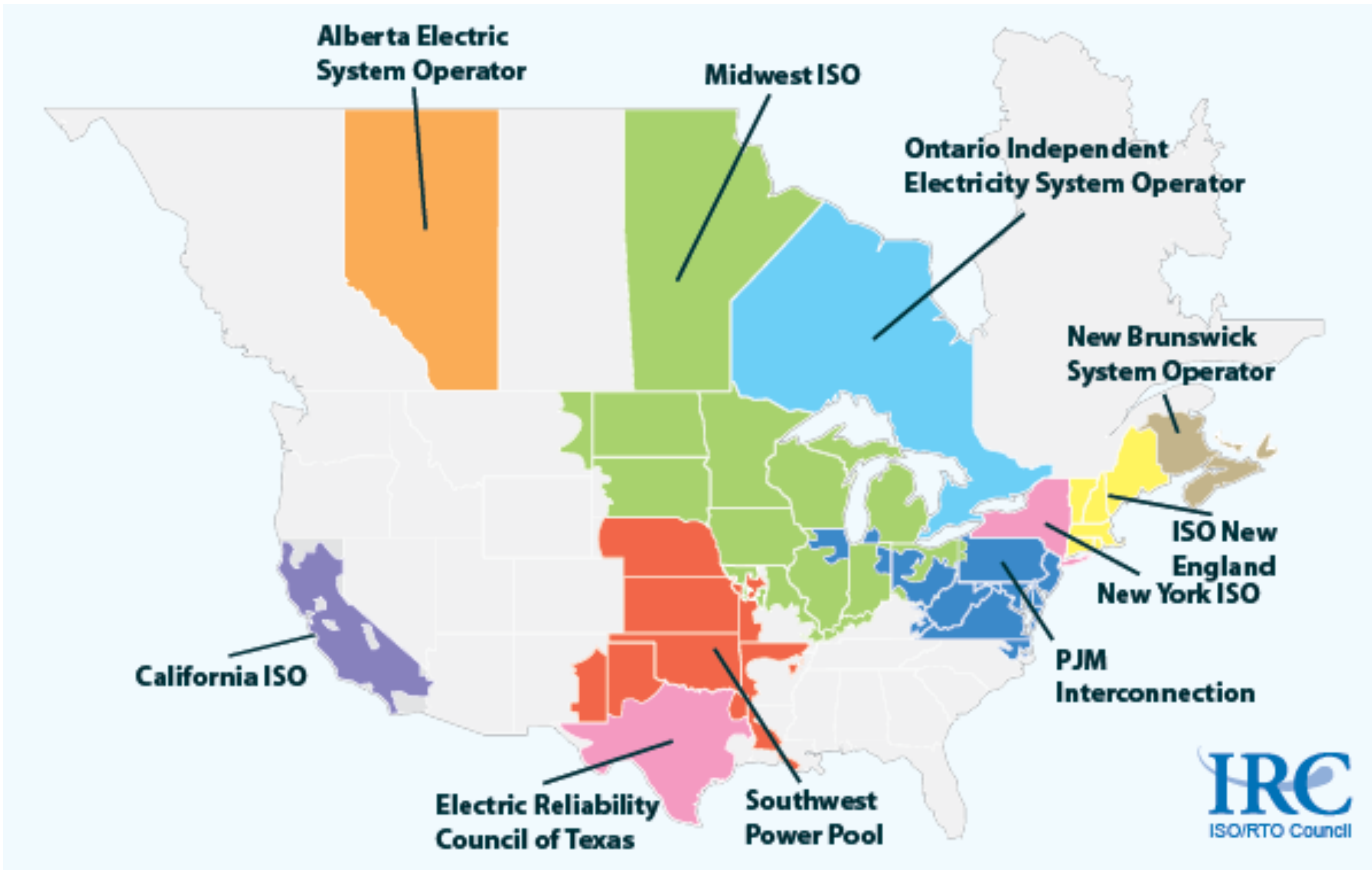
A Country Divided

- RTOs and ISOs serve a substantial portion of the U.S. Population
- Yet, the use of markets to coordinate electricity generation appears to have reached a plateau.

A Divided Continent in Terms of Electricity Markets



Has Restructuring been a Failure?

- Blumsack and Lave (2006) have argued that the restructuring of the electricity sector has been a failure because of market manipulation

- Van Doren and Taylor (2004) have also concluded that electricity restructuring has been a failure and that “vertical integration may be the most efficient organizational structure for the electricity industry.”

Load Forecasting

- Whether or not electricity generation is coordinated through markets, minimizing generation costs requires highly accurate day-ahead forecasts of electricity demand.
- In the Pacific Gas and Electric (PG&E) aggregation zone managed by the California Independent System Operator (ISO), the root mean squared forecast error was approximately 3.8 percent of mean load over the period 1 April 2009 through 31 March 2010.

PG&E's Service Territory

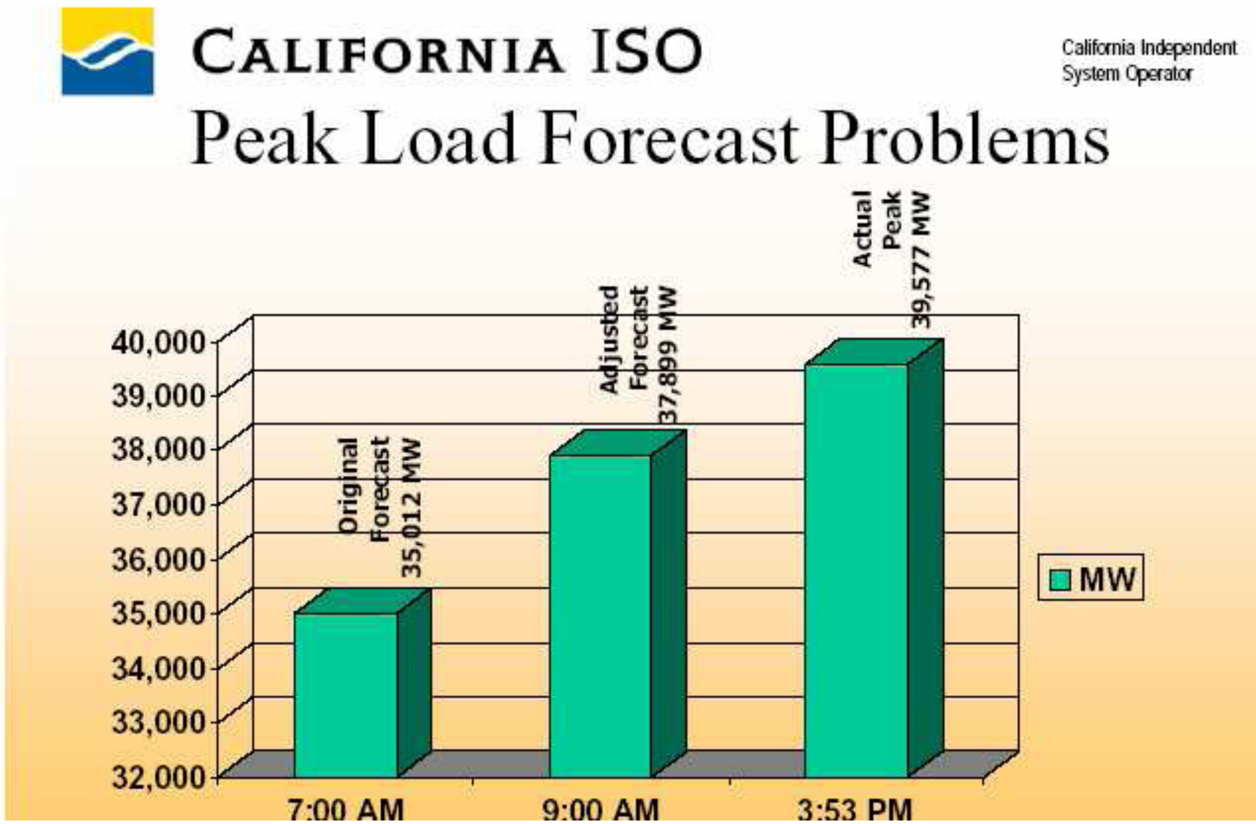
The “Delta Breeze” Phenomenon

- A load forecasting challenge faced by the California ISO (CAISO) is the “Delta Breeze” phenomenon, a sea breeze carrying cool air from the ocean into the San Francisco Bay area and up to 100 miles inland.
- An absence of the breeze can lead to significantly higher electricity load.
- If a Delta Breeze occurs but is unanticipated, forecasted load will be substantially higher than actual and CAISO will have over committed to generation supply.
- If a Delta Breeze is forecast but does not occur, then reliability may be challenged because of inadequate scheduled generation.
- The CAISO has reported difficulty in predicting the Delta Breeze.

Load Forecasting Errors and Reliability

On May 28 2003, the day-ahead peak forecasted load in CAISO was 35,012 MW while the actual peak load was 39,577 MW. As a consequence, a stage 1 alert had to be declared.

CAISO Peak Load Forecast Problems (May 28, 2003)



Source:Scripps Institute of Oceanography and Science Applications International Corporation

Load Forecasting Errors and Outcomes in PJM's Real-Time Market

- From 1 June 2007 through 31 December 2009, the average real-time price of electricity in the PJM RTO was approximately 12 percent higher relative to the day-ahead price when actual load was higher than forecasted.
- The average real-time price of electricity in the PJM RTO was approximately 5 percent lower relative to the day-ahead price when actual load was less than forecasted.

Day–Ahead Load Forecast Errors in Other Control Areas

- Approximately 16 percent of the days in New York City had a root-mean-squared-day-ahead-forecast-error in excess of five percent of daily mean load over 1 January 2000 - 31 December 2008 period.
- Approximately seven percent of the days in France had a root-mean-squared-day-ahead-forecast-error in excess of five percent of daily mean load over the 1 November 2003 - 31 December 2007 period .

Day–Ahead Load Forecast Errors in Other Control Areas (Cont'd)

- *Belgium*: The RMSE of the day-ahead forecast of system load was approximately 4.6 percent of mean load over the period 1 January 2010 – 31 December 2010.
- *ERCOT*: The RMSE of the day-ahead forecast of system load was approximately 4.6 percent of mean load over the period 5 December 2009 – 30 November 2010.
- *PJM*: The RMSE of the day-ahead forecast of system load was approximately 3 percent of mean load over the period over the period 1 January 2009 – 31 December 2009
- *Amprion* (*Germany*): The RMSE of the day-ahead forecast of demand was approximately 4.2 percent over the period 1 April 2008 – 31 December 2010.

The Efficient Market Hypothesis

If day-ahead markets for electricity are informationally efficient, then day-ahead prices will reflect the load forecast generated by the system operator as well as information processed by and consequent insights of all market participants.

Can Day-Ahead Market Outcomes Contribute to More Accurate Load Forecasts?

- Market efficiency implies that day-ahead prices will reflect all available meteorological information including the forecasts by any proprietary models that are more accurate than that employed by the system operator.
- On this basis, we hypothesize that descriptive measures of the distributional characteristics of day-ahead prices will be useful in predicting the day-ahead load.
- Because forecast accuracy is likely impacted by the complexity of the load profile, we also hypothesize that measures of the "shape" of the day-ahead forecasted load profile will be useful for day-ahead load predictions.

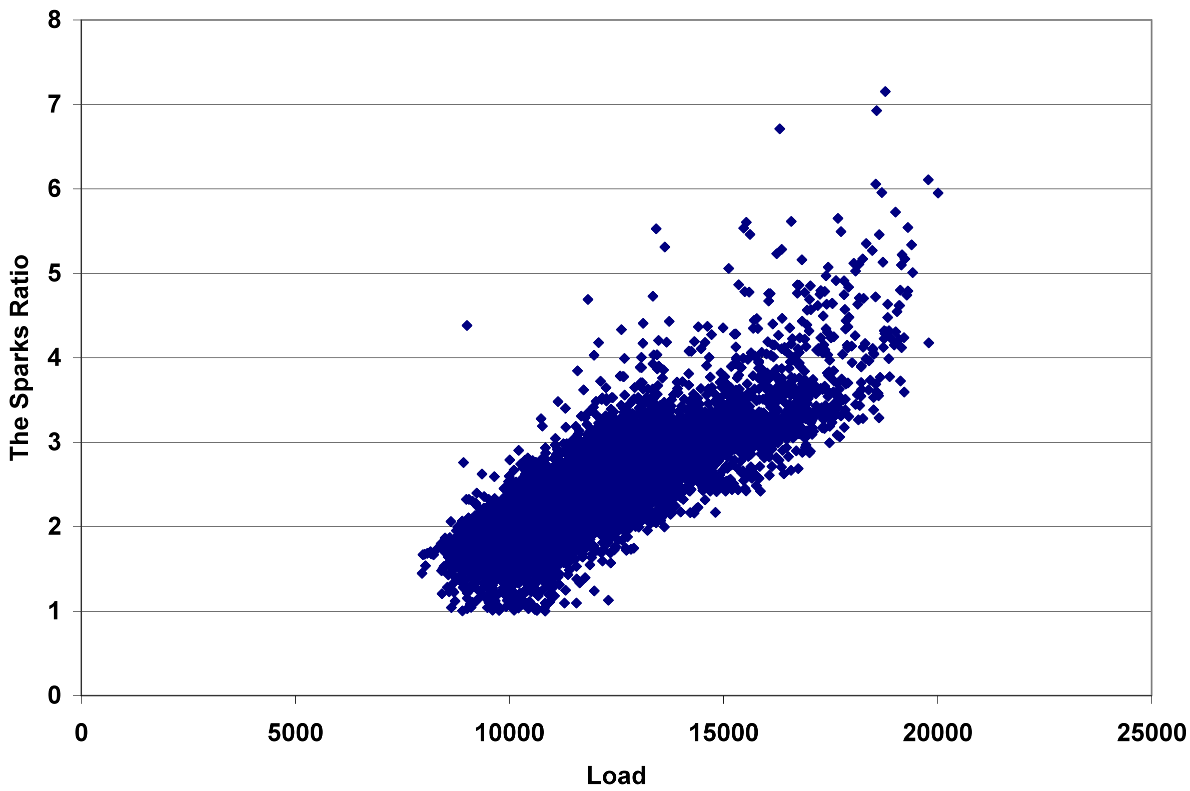
The Day-Ahead Sparks Ratio: A Key Metric of Expected Outcomes

- $$\text{SparksRatio} = \frac{DaReferenceLMP}{\boldsymbol{PGAS}}$$

Where *DaReferenceLMP* is a Day-Ahead LMP at a recognized reference location

PGAS is the spot price of natural gas in USD per MWh.

Day-Ahead Sparks Ratio and Actual Load for the PG&E LAP in the California ISO, 1 April 2009 – 31 March 2010



The Dependent Variable

Natural logarithm of the ratio of actual hourly load to forecasted hourly load

The Explanatory Variables

SparksRatio
Coefficient of Variation in the Hourly Price over the 24 hours
Positive Skewness in Price
Negative Skewness in Price
Ratio of Forecasted Load to the Peak for the Day
Ratio of the Hourly Forecasted Load to Minimum for the Day
The Day's Peak Forecasted Load
The Day's Minimum Forecasted Load
Coefficient of Variation in Forecasted Load over the 24 hours
Positive Skewness in the Forecasted Load
Negative Skewness in the Forecasted Load
Forecasted Load
Binary Variables for day of the Week
Binary Variables for Hour of the day
Binary Variables for Month
Binary Variable for "daylight"

Data and Sample

- The model employs data from the PGE aggregation zone.
- All electricity and fuel prices obtained from CAISO.
- The sparks ratio was calculated using PGE apnode reference and natural gas prices.
- Sample Period: 1 April 2009 – 31 March 2010, excluding days with non-positive (≤ 0) PGE reference prices.
- Number of observations: 8,514

Econometric Issues

- ***Functional Form***: Though the relationships are highly unlikely to be strictly linear, there is no basis, theoretical or otherwise, to assume any particular nonlinear form.
- ***ARMA disturbances***: Time series regressions using high frequency data are often plagued by autoregressive error structures that are *not* easily accommodated using standard AR(p) methods.

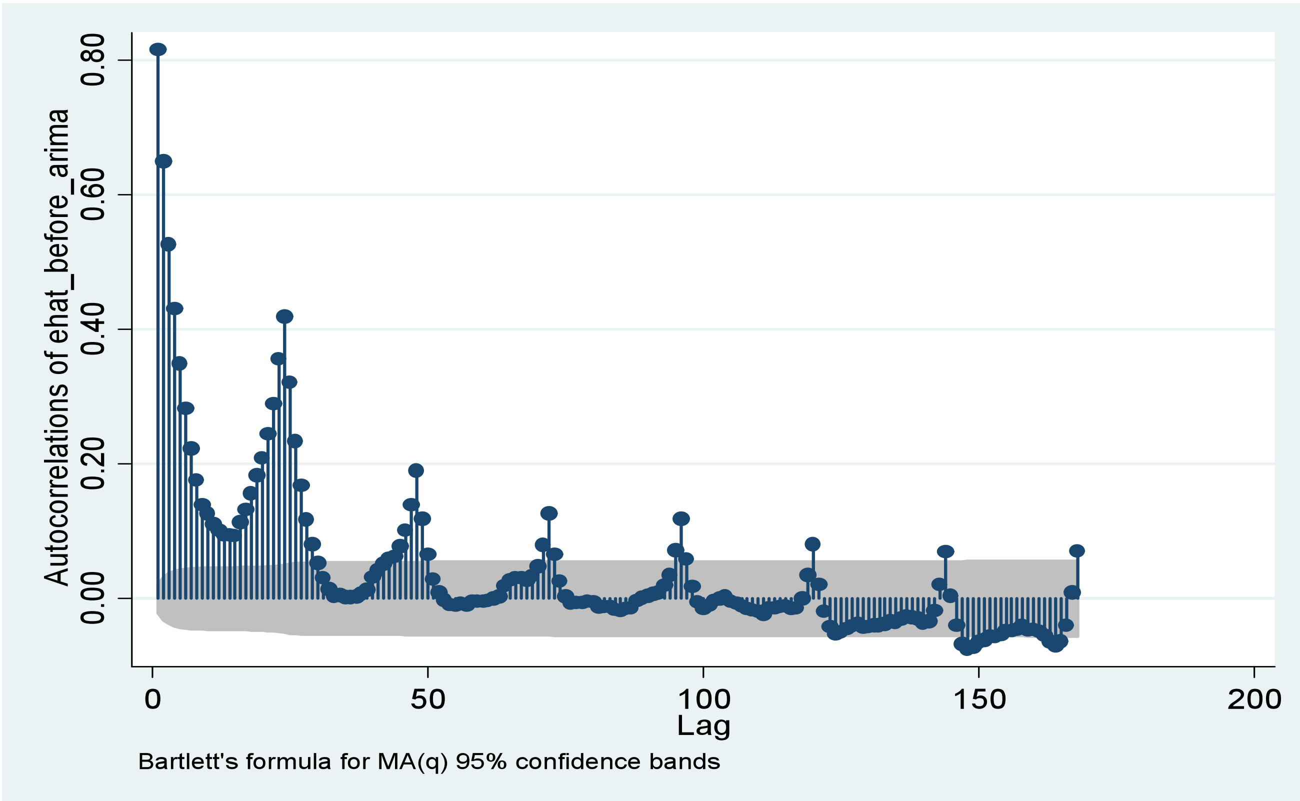
Functional Form

The model was estimated using the *multivariable fractional polynomial* (MFP) model. This is a useful technique when one suspects that some or all of the relationships between the dependent variable and the explanatory variables are non-linear (Royston and Altman, 2008), but there is little or no basis, theoretical or otherwise, on which to select particular functional forms.

Results of the MFP Analysis

	Powers	Powers
SparksRatio	2	
Coefficient of Variation in the Hourly Price over the 24 hours	-2	
Positive Skewness in Price	1	
Negative Skewness in Price	1	
Ratio of Forecasted Load to the Peak for the Day	1	
Ratio of the Hourly Forecasted Load to Minimum for the Day	1	
The Day's Peak Forecasted Load	3	
The Day's Minimum Forecasted Load	1	
Coefficient of Variation in Forecasted Load over the 24 hours	3	
Positive Skewness in the Forecasted Load	-2	-1
Negative Skewness in the Forecasted Load	-2	-1
Forecasted Load	2	

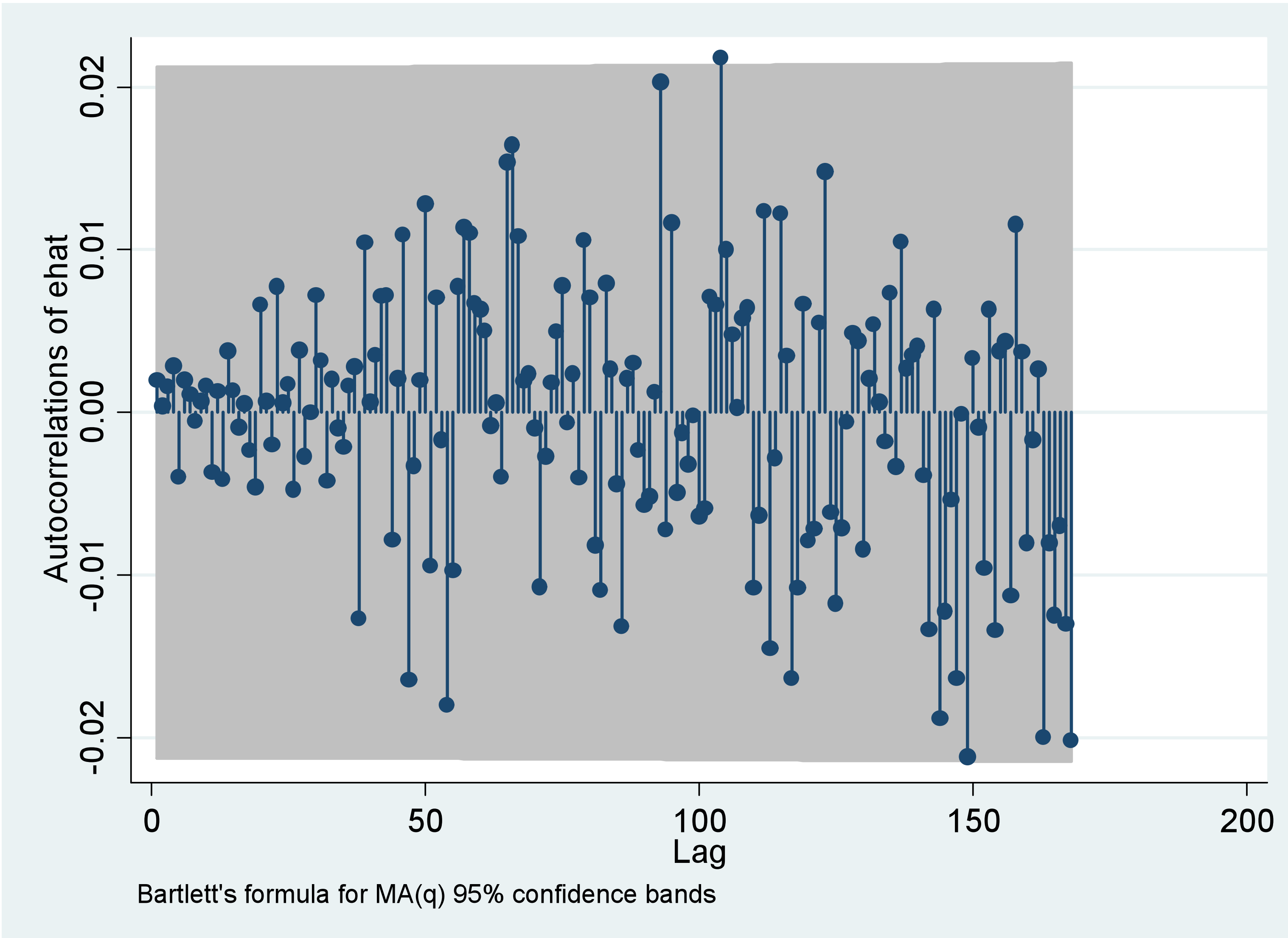
Residual Autocorrelations Before ARMA Estimations



Modeling the ARMA Disturbances

- **AR(*p*):** The modeled lag lengths are *p* = 1, 2, 3, 4, 24, 48, 72, 96, 120, 144, 168, and 192.
- **MA(*q*):** The modeled lag lengths are *q* = 1 through 36, 48, 65, 72, 96, 120, 144, 168, and 192

Residual Autocorrelations After ARMA Estimation



Further Post-Estimation Residual Analysis

- Portmanteau (Q) tests for white noise were conducted for lags 1 through 100, 120, 144, and 168. All p-values were well above all standard significance levels, failing to reject the null hypothesis of a white noise error structure.

Estimation Results

- Almost all estimated coefficients on binary variables representing day of the week, hour of the day, and month of the year are statistically significant.
- The binary variable representing “Daylight” is also statistically significant.
- 11 of the remaining 14 coefficients (Sparks Ratio, etc.) are statistically significant.
- The correlation between actual and predicted values of the dependent variable is 0.9395.

Out of Sample Forecast

- Using the parameter estimates, an out of sample *dynamic* forecast was performed for the period 1 April 2010 through 31 March 2011.
- Over this time period, the RMSE of the day-ahead forecast was 485 MWh which is equivalent to about 4 percent of mean load.
- The RMSE of the revised forecast is 374 MWh which is equivalent to about 3.1 percent of mean load.

Future Research Efforts

- Apply the modeling framework to other control areas.
- How does the model perform when natural gas is not the dominant fuel?
- How does the model perform for markets that are “lightly” regulated?
- Incorporate predicted weather conditions into the analysis.

Conclusions

- The results indicate that it is possible to reduce substantially the load forecasting errors by revising the forecasts based on the systematic component of the errors.
- The out of sample reduction in the forecast error suggests that application of the methodology has potential to enhance reliability and reduce balancing costs.
- More generally, the results are consistent with the view that market prices in California's electricity market are determined by economic fundamentals.
- In general, the results suggest that there is merit in using markets to allocate scarce resources efficiently.